BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF:

Joint Application of Questar Gas	)	
Company, the Division of Public	)	
Utilities, and Utah Clean Energy	)	**Docket Number 05-057-T01**
For the Approval of the Conservation	)	
Enabling Tariff Adjustment Option	)	
And Accounting Orders	)	

SUPPLEMENTAL REBUTTAL TESTIMONY
OF
DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 6455 Overton Street, Baton Rouge, Louisiana. I previously filed rebuttal testimony in this proceeding on behalf of the Committee of Consumer Services ("Committee").

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. The purpose of my supplemental rebuttal is to address a number of questions posed by the Commission Staff ("Staff") during the course of the June 7, 2006 technical conference on the issues in this proceeding. Prior to the meeting, Staff issued a list of questions for discussion including:

(1) Relationship of Earnings to Net Revenues;

(2) Additional Benefits of Decoupling;

(3) Use per Customer Data;

(4) Changes in Risk and Risk Shifting; and

(5) Alternatives Comparison.

During the technical conference, Staff directed parties to prepare responses to these issues in their surrebuttal testimony. Since that time, a new procedural order has been issued that has directed responding parties to file this information as supplemental rebuttal.

Q. HOW IS THE REMAINDER OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY ORGANIZED?

A. My supplemental rebuttal testimony is organized in an order similar to the Staff issues list. However, I do address a number of topics included in the “alternatives comparisons” section first (Issues 4(d) and 4(e)), since I think there are considerable opportunities for developing a progressive policy supporting the implementation of cost-effective demand-side management (“DSM”) in Utah. The topics outlined under Section 2 of the issues list have been compressed into other sections of my testimony. For instance, issues 2(a) and 2(b) are included in my discussion of “risk and risk sharing” while issue 2(c) is addressed in the section addressing “earnings and net revenues.” Specifically, my testimony is organized into the following sections:

Section II: Alternative DSM Promotion Policies;

Section III: Relationship of Earnings to Net Revenues;

Section IV: Use per Customer Data;

Section V: Changes in Risk and Risk Shifting;

Section VI: Alternatives Comparison; and

Section VII: Recommendations and Conclusions

Q HOW WOULD YOU CHARACTERIZE THE POSITIONS IN THE TECHNICAL CONFERENCE?

A The technical conference reflected a number of strong opinions concerning the merits of revenue decoupling and the appropriate policies for promoting cost-effective DSM. Amid the differences, these areas of consensus stood out:

(1) All parties want to promote the efficient use of natural gas in Utah; and

(2) All parties see opportunities for progressive policies to promote natural gas efficiency.

The biggest challenge is how to achieve each of these important goals.

Q HOW WOULD YOU CHARACTERIZE THE MAIN AREAS OF CONTENTION?

A There appears to be two primary areas of contention in this proceeding:

(1) Identifying the real motivating factors for promoting (or not promoting) DSM; and

(2) Determining which progressive policy should be adopted over a range of different alternatives.

Q HOW DO THE POSITIONS ON DSM INCENTIVE ISSUES DIFFER?

A The Joint Applicants, as noted in their various filings and positions at the technical conference, believe that utilities have strong disincentives to promote DSM. Their position is that a utility's financial position will be significantly harmed if DSM is required without the adoption of a policy like the proposed CET. Other parties, including those representing most all of the ratepayer groups in Utah (i.e., residential and small commercial, low income, industrial), take the position that utilities have a statutory obligation to provide least-cost service to their customers, which includes both supply and demand-side resources. If providing least-cost service creates a financial difficulty for the utility, it has the ability to seek rate relief from the Commission. Further, ratepayer groups have also pointed out there are a number of different mechanisms to address the Company's reservations about promoting DSM without resorting to the CET proposal.

Q IF THE OPPOSING PARTIES BELIEVE THAT THE UTILITY HAS AN OBLIGATION TO PURSUE LEAST-COST DSM, WHERE IS THE OPPORTUNITY FOR A "PROGRESSIVE POLICY?"

A The progressive policy – in the sense that it advances the movement of energy efficiency – would be for the Commission to order Questar to develop and implement cost-effective DSM programs. While the Commission should remind the Company that it has this obligation, it may also be the case, as the Questar's expert in the technical hearing noted, that having an active and willing participant in the DSM process may be more productive than one that is recalcitrant.

Q IS THE PURPOSE OF YOUR RECOMMENDATION TO REJECT THE CET PROPOSAL AN ATTEMPT TO PREVENT THE COMPANY FROM EARNING ITS AUTHORIZED RATE OF RETURN?

A No and unfortunately this appears to be a fundamental misunderstanding that the Company expressed in the technical conference. The purpose of my recommendation was to advise the Commission against adopting a policy that was not well-defined and shifted retail sales revenue recovery risk to customers. I believe that the biggest source of confusion (and disagreement) over the decoupling recommendation is the Company's dual justifications. On the one hand, the Company notes that the proposal will remove disincentives to promote DSM. On the other hand, it argues that the proposal will assist in what it refers to as its "declining average use problem" and the challenges that problem poses in allowing the Company to earn its authorized rate of return. While it is clear that revenue decoupling will help the Company secure a guaranteed revenue stream, the DSM benefits to customers (and which types of customers may benefit) are at this time unclear. The CET proposal, in keeping with one of the general findings reached in the revenue decoupling report recently prepared by the National Regulatory Research Institute ("NRRI"), presents clear benefits to the utility and unclear benefits to ratepayers.[1]

Q ARE THERE ALTERNATIVES THAT THE COMMISSION COULD CONSIDER THAT PROMOTE DSM AND AT THE SAME TIME DO NOT UNNECESSARILY SHIFT RISK TO RATEPAYERS?

A. Yes and I have provided summaries and examples of three different alternatives that I believe are superior to the current CET proposal. These summaries are included in Supplemental Rebuttal ("SR") Exhibit CCS-2.1 through SR Exhibit CCS-2.3. I will discuss each alternative in the following section of my testimony. However, if the Commission adopts one of these

[1] Ken Costello. *Briefing Paper: Revenue Decoupling for Natural Gas Utilities*. National Regulatory Research Institute, April 2006: 18, 23.

alternatives, it should do so conditionally upon the Company's provision of a complete listing of DSM programs, estimated savings and costs, clear monitoring and evaluation goals, and accounting and ratemaking treatment practices for the entire three-year pilot program.

<u>II ALTERNATIVE DSM PROMOTION POLICIES</u>

Q WOULD YOU PLEASE SUMMARIZE THE ALTERNATIVES THAT YOU PROPOSE?

A Yes. Exhibit SR CCS-2.1 through SR Exhibit CCS-2.3 presents three different policy alternatives that the Commission could consider that I believe are superior to the current CET proposal. These alternatives are being offered in response to the inquires made by Staff in its technical conference issues list; in particular, Section 4(d) and 4(e).

- The first alternative is an incentive regulation approach that would base the target goals on an achieved benefit/cost ("B/C") ratio.
- The second alternative is also an incentive regulation approach. This approach would base the target on some forecasted level of total natural gas savings.
- The third alternative is a partial revenue-sales decoupling approach. This approach would make adjustments for economic, price, and exogenous trend shifts in use per customer that are unrelated to specific Company-provided DSM programs.

Q WOULD YOU PLEASE DISCUSS THE FIRST ALTERNATIVE WHICH YOU DESCRIBE AS AN INCENTIVE APPROACH?

A My first recommended alternative is an incentive-based mechanism that would be based on an achieved B/C ratio for DSM programs. Here, a target or benchmark B/C ratio is established. This can be done by evaluating the estimated B/C ratios for the respective plans offered by the Company at some future date. The benchmark could also be influenced by some best practice experiences in other states. I propose that a dead-band be established around this ratio within which neither penalties nor rewards would be set. Exceptional performance outside of the dead-band would be rewarded on some fixed dollar per decatherm ("Dth") saved. Sub-standard performance, where the B/C ratio falls below the lower end of the dead-band, would be penalized. A series of blocks could also be established (though not required) that would increase the fixed incentive amount as higher levels of efficiency are reached. A generalized example has been provided on the second page of SR Exhibit CCS-2.1. Specific numbers cannot be included in this proposal since that requires specific DSM programs, which the Company is reportedly in the process of developing. Specific parameters can be added to this alternative once those DSM plans are provided to parties.

Q HAS THIS APPROACH BEEN UTILIZED IN ANY OTHER STATE?

A No, this would be a unique approach and it does include some potential implementation issues. However, this alternative is one that instead of being targeted to a gross amount of natural gas savings, irrespective of cost, would reward efficient DSM delivery. I point that benefit out because during the technical conference, there was some discussion about past DSM programs around the country. From the discussion, it appeared that energy efficiency advocates were disappointed with some of the early results associated with DSM implementation since many of these early programs turned out to be more about marketing and reputation-building than delivering exceptional energy efficiency savings. Since the Company has virtually no DSM experience to date, and will be starting its initiatives from scratch, this type of approach would help discourage these inefficiencies (or perceptions of inefficiencies) from occurring.

Q DO YOU THINK ANY PROBLEMS COULD ARISE IN UTILIZING THIS TYPE OF APPROACH WITHIN A STRICT THREE YEAR PERIOD?

A. Perhaps, although it is unclear because the Company has not provided any DSM programs at this point. In particular, there is a potential for realized savings lags that may fall out of the three-year pilot window, and for which the Company would receive no benefit. If this alternative were adopted, the specific time duration for the pilot may have to be altered. Further, it could be the case that over time, diminishing returns would begin to occur as the Company picks the low-hanging fruit off the program development tree. Bear in mind that at this date, the Company has yet to even plant the tree. So the commencement date, the duration of the pilot program, and any continuation of the program beyond the pilot period may need to consider an adjustment to the target B/C ratio. Again, this is an empirical issue dependent upon the Company's proposed DSM programs.

Q HOW WOULD YOU RECOMMEND DEALING WITH SOME OF THESE IMPLEMENTATION ISSUES?

A I recommend that the Commission issue an order directing the Company to have a complete list of DSM programs, with estimated costs and benefits and other relevant implementation information by some date certain (to the extent **complete** information is not provided during the course of the remainder of this proceeding). Parties to this proceeding should be required to present their recommendations on B/C ratios, bands, and incentive levels by some later date certain; this later date being set such that parties get a reasonable chance to review submitted programs. The Commission could potentially issue an order soon after the parties have submitted recommendations, and DSM programs could begin soon after that date. The Committee understands that on May 25, 2006, the Company secured the services of Nexant for a Market Characterization & Delivery Evaluation to be completed by July 5, 2006. Parties may be able to use this very preliminary survey to develop the parameters needed for any one of my alternative DSM incentive approaches, which in turn, would advance the DSM process and take advantage of the Company's reported DSM efforts in the last several weeks.

Q CAN YOU EXPLAIN THE SECOND ALTERNATIVE?

A The second alternative is a more traditional DSM incentive-based plan. Here a fixed target level of savings (in Dth) is established for the baseline. Again, I would propose a dead-band surrounding the target level with rewards for savings outside the band, and penalties for savings under the band. A series of blocks could also be established (though not required) that would increase the fixed incentive amount as higher levels of savings are reached. Incentive amounts, bands, and targets would have to be established once the Company provides its three-year portfolio of proposed DSM programs.

Q HAVE ANY OTHER STATES UTILIZED MECHANISMS OF THIS NATURE?

A Yes. There are a number of states that have utilized incentive mechanisms as highlighted in Exhibit CCS-2.9 of my rebuttal testimony.

Q CAN YOU PLEASE EXPLAIN THE REMAINING ALTERNATIVE?

A The remaining alternative is referred to as a statistical re-coupling approach. The approach is “statistical” in nature because it uses parameter estimates from statistical demand models to adjust the revenue decoupling mechanism true-up amounts for exogenous factors like economic and price risk, as well as trend changes in consumption that go beyond utility conservation efforts. I believe the approach can be more appropriately characterized as a “partial decoupling” method since it primarily adjusts for changes in DSM-created changes in sales, but nothing else. Thus, it should remove the Joint Applicants’ claims of utility disincentives for promoting its own conservation programs since revenues would be adjusted for sales losses associated with these DSM efforts. At the same time, the traditional risk relationships between the utility and ratepayers would be preserved.

Q HOW DO YOU MAKE THESE ADJUSTMENTS?

A At least three statistical measures are extracted from the utility’s load forecast to make these adjustments. These measures include the price elasticity of demand, the income elasticity of demand, and an adjustment for exogenous changes in usage that have nothing to do with utility DSM efforts. Stated simply, these elasticity parameters (price, income) estimate how natural gas demand changes with a change in price and income, respectively, while the trend adjustment corrects for other factors having nothing to do with utility actions. The elasticity estimates (and trend adjustment) could come from the Company's most recent IRP that includes an income elasticity of 0.05 and a price elasticity of -0.06 on a use per customer basis. The Company's most recent IRP also has a 2.7 Dth/customer adjustment for trend changes in usage that could be utilized in this alternative approach.

Q WHY ARE THESE ADJUSTMENTS IMPORTANT?

A The adjustments are important because they would keep the risk of sales variations due to economic conditions, price changes, and customer-initiative efficiency with the Company instead of shifting those risks to ratepayers (as is currently the case with the proposed CET). Preserving this risk relationship between the Company and its ratepayers would eliminate the need to make some other type of risk-shifting adjustment like a change in the Company's allowed rate of return.

<u>III RELATIONSHIP OF EARNINGS TO NET REVENUES</u>

Q WHAT IS THE RELATIONSHIP BETWEEN USE PER CUSTOMER AND NET EARNINGS?

A The Commission Staff's technical conference issues list highlighted a mathematical representation included in the NRRI revenue decoupling report describing the relationship between earnings and changes in revenue. The relationship has been replicated in SR Exhibit CCS-2.4. An explanation in non-mathematical terms is provided below the equation. The representation has been provided in the report in order to show the overall relationship of earnings and revenue growth, but needs to be expanded one more level in order to explain the impacts of changes in use per customer on overall revenues, and subsequently, on overall earnings.

Q HAVE YOU PROVIDED A COMPARABLE EXAMPLE SHOWING THIS RELATIONSHIP?

A Yes, it has been provided in SR Exhibit CCS-2.5. This exhibit shows that changes in total usage are a function of (1) the change in usage per customer associated with existing customers and (2) the new usage associated with customer growth. If usage increases resulting from customer growth outpace the usage decrease associated with reduced usage per customer (from existing customers), then total usage will increase. The inverse would occur if usage from customer growth was less than the total decreases created by reduced use per customer. If prices and costs are held constant, then earnings will continue to increase if new customer-related usage growth outpaces the decrease in use per customer for existing customers. The inverse would occur if new customer-created usage was less than the decreases in use per customer for existing customers; again, holding other factors constant. Thus, the impact that decreases in use per customer has on earnings growth can be offset for a utility serving a growing service territory. Utilities that serve stagnant, or very slow growing service territories, could see earnings attrition if usage per customer falls. All of these relationships are based upon the premise that other factors are held constant.

Q IS IT POSSIBLE TO FORM AN ESTIMATE OF CHANGES IN NET REVENUES FROM CHANGES IN USE PER CUSTOMER BASED ON THE COMPANY'S ACTUAL DATA?

A Yes. I have presented a series of different exhibits that highlight some of these relationships from information included in the Company's Results of Operations. SR Exhibit CCS-2.6 shows the offsetting impacts on total usage created by (1) changes in use per customer and (2) changes associated with customer growth. Between 2001 and 2002, the Company saw GS1 sales decrease by 47,033 Dth. GS-1 customers during that period grew by 2.6 percent, or by some 18,320 customers. Usage decreases associated with decreases in use per customer were of a comparable percent (2.6 percent), or from 118.97 Dth/customer to 115.84 Dth/customer. As seen from the last three columns, the impact on total consumption was close to offsetting between the two impacts. Total usage reductions resulting from decreased use per customer were estimated to be around 2,169,247 Dth, while increased usage from new customers is estimated to be 2,122,214 Dth. The net change (subtracting the two) was a decrease of 47,033 Dth.

Q HOW HAVE USAGE TRENDS CHANGED IN LATER YEARS?

A There have been several years of both increases and decreases in total usage. Between 2002-2003, both use per customer and usage associated with new customers increased. Increases in annual use per customer is estimated to have contributed 2,175,756 Dth to overall sales. The increase in use from new customer growth was 2,275,842 Dth. The total annual change in sales that year is the sum of these two impacts or 4,451,598 Dth. Other years have seen comparable movements; in the most recent full year, use per customer reductions contributed to a decrease of 924,563 Dth, while increased usage associated with customer growth was 3,588,674 Dth, resulting in a net positive change of 2,664,111 Dth. Over the past five years, there have been two years of decreases in usage associated with the decline in use per customer accounting for 907,601 Dth. There have also been two years of substantial increases created by customer growth accounting for 7,115,709 Dth. The net period change has been an increase in usage (net of decreases created by use per customer declines) of 6,208,108 Dth. In other words, the Company has seen total usage increase of about 6 billion cubic feet ("Bcf") despite the decrease in average use per customer.

Q HAVE YOU DONE A COMPARABLE ANALYSIS FOR REVENUES?

A Yes, SR Exhibit CCS-2.7 presents a comparable analysis on a revenue basis. Two different columns have been provided that show the estimated changes in revenues associated with a decrease in use per customer versus the increase in revenues associated with changes in customer growth. Between 2001 and 2002, I have estimated that revenues decreased by $2.8 million dollars due to decreased usage per customer. Estimated revenue increases due to customer growth for that period was $4.9 million, resulting in a net increase in revenues of $2.1 million. In the subsequent year, it is estimated that revenues increased for both impacts since average usage per customer and customer growth were both positive and significant (net positive change of $17.8 million).

Q DO YOU ANTICIPATE THESE TRENDS CONTINUING INTO THE FUTURE?

A They could at least until 2009. Exhibit SR CCS-2.8 presents a forecast of potential usage trends using information from the Company's current IRP. I have assumed customer growth of 25,000 per year for 2006-2007 and 22,000 per year from 2008-2010. Average usage per customer is assumed to decrease by roughly 2.7 Dth per customer per year. As shown in SR Exhibit CCS-2.8, usage associated with customer growth more than offsets estimated impacts from decreased usage per customer until about 2009. At that point, two years of total usage decreases are forecasted to set in (holding other factors constant). However, in total, those two years of forecasted usage decreases are only 260,737 Dth – substantially less than the two years of decreases already seen in the past five years (i.e., 907,601 Dth).

Q HAVE YOU ATTEMPTED TO ESTIMATE THE FINANCIAL IMPACT OF THE RECENT CHANGES IN USAGE?

A Yes. SR Exhibit CCS-2.9 provides that information. The exhibit consists of three pages: (1) a summary page; (2) detailed calculations on the estimated financial impact of changes in use per customer; and (3) detailed calculations on the estimated financial impact of changes from customer growth. The first summary page of the exhibit shows that for the better part of the five year period, the positive financial contributions of customer growth exceeded the negative implications of decreases in use per customer. The only exception was in 2003 when positive use per customer is estimated to have actually contributed more to the overall financial results than the increase in customer growth. The information at the bottom of the summary table provides comparable information for the return on equity ("ROE").

Q IF USAGE PER CUSTOMER DOES NOT APPEAR TO BE DRAGGING DOWN THE COMPANY'S FINANCIAL PERFORMANCE, WHERE IS THE PROBLEM?

A The problem, if there is one, appears to be associated with the cost of providing service to new these customers. Page 1 of SR Exhibit CCS-2.9 shows that changes in rate base and capital elements have the largest negative impact on the Company's achieved ROR – not changes in usage. SR Exhibit CCS-2.10 shows the Company's recent investment trends on an average and incremental basis. The bottom two rows are the more informative. Average net utility plant in service per customer ranges between $835 to $935 per customer. However, the incremental net utility plant cost per change in customer is significantly higher at an average of around $1,650 for the past several years.

Q WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A It appears that the real challenge the Company faces is its ability to recover the costs associated with serving new customers. This has nothing to do with DSM, and also has little to do with decreasing use per customer (for existing customers), or usage in general. The Joint Applicants are attempting to use a **demand-related** regulatory adjustment mechanism, historically used to support conservation, as a means to solve a **<u>cost-related</u>** problem (having nothing to do with DSM). Issues related to serving new customers are cost recovery and rate design in nature. Trying to use decoupling as a means of correcting this problem is akin to creating an attrition adjustment. This would be inconsistent with the purpose of decoupling as it has been adopted in other states. Decoupling should be used as a mechanism for promoting DSM, rather than making earnings corrections caused by the cost of adding new customers. If the Company has a problem with covering the cost of serving these new customers, the problem should be dealt with in the traditional ratemaking process and not through revenue decoupling.

Q EFFICIENCY ADVOCATES IN OTHER DECOUPLING PROCEEDINGS AROUND THE U.S. HAVE PRESENTED SOME RATHER OMINOUS EXAMPLES OF SHAREHOLDER PENALTIES THAT COULD RESULT FROM DSM IMPLEMENTATION. DO THESE REPRESENTATIONS PROVIDE COMMISSIONS WITH USEFUL INFORMATION?

A No, such examples are incomplete representations of how earnings and financial performance are impacted by changes in usage, including the impact of DSM. A common example given in the past by efficiency advocates starts with the assumption that usage will decrease by 1 percent per year with each year adding savings equal to the savings achieved during the pervious year. The resulting negative financial impacts can be quite large and alarming, and in a recent proceeding in Washington, efficiency advocates estimated that the financial impacts to the utility in question (Pacificorp) could be as great as $21.0 million over a 5 year period.[2]

Q. CAN SUCH AN EXAMPLE BE MISLEADING?

A. Yes. I have applied similar assumptions to Questar's financial results in SR Exhibit CCS-2.11. This generalized example would incorrectly suggest that the Company's shareholders would be harmed by as much as $13.0 million from DSM implementation. However, there are problems with such a simple example. First, it fails to take into consideration the tax impact associated with the reduction in revenue. If revenues are reduced as a result of decreased sales, then income taxes would also be reduced. Therefore, a 1 percent reduction in sales would result in a negative $8.0 million impact on shareholders. It is important to point out that even at this limited point of analysis, a 1 percent sales reduction from DSM is clearly hypothetical since the Company has yet to provide any specific DSM plans or savings goals.

Q. ARE THERE OTHER PROBLEMS WITH SUCH A SIMPLE EXAMPLE?

A. The example essentially assumes that there are no offsetting factors impacting the Company's overall financial performance. As I earlier explained, there is substantial customer growth on Questar's system. In the past, this growth in customers and sales has contributed to the Company's positive financial performance and this should be taken into consideration in any example of the overall financial implications of utility-promoted DSM.

Q HAVE YOU CONDUCTED A MORE ACCURATE ANALYSIS?

[2] Direct Testimony of Ralph Cavanagh, Before the Washington State Utilities and Transportation Commission, Docket No. UE-050684, November 2, 2005.

A. Yes, Exhibit CCS 2.11 presents a more balanced analysis while continuing to assume that the Company had DSM programs in place that would result in a 1 percent reduction in sales. However, this potential DSM-created reduction would be offset by an increase in sales due to the addition of new customers. The increased sales associated with customer growth over a 3-year pilot program would result in an increase in shareholder wealth of $12.3 million. The net impact of the sales losses associated with DSM and customer growth is a positive $4.2 million in shareholder wealth. For this example, I have used the Company's most recent forecast for customer growth that is included in its IRP. I have also assumed that the $1,700 incremental investment cost per customer trend experienced over the past several years, continues into the future. In reviewing this exhibit, it is important to remember that the income impacts are **<u>incremental</u>**, not total. Holding other factors constant, total net income for the Company would still be positive in any given year and other factors, like changes in operating (but not incremental investment) costs, would need to be considered in order to determine the Company's overall financial performance. So for instance, in 2008-2009, the net income impact, holding other factors constant, would decrease overall achieved earnings by a very small 0.07 percent, despite assumed significant cumulative DSM savings in the amount of over 3 percent of total sales and a continued high incremental investment cost per customer.

Q WHAT WOULD BE NEEDED TO FORM A MORE ACCURATE ANALYSIS OF THE IMPACT OF DSM ON POTENTIAL EARNINGS?

A The most important information needed to do this analysis is the level of DSM the Company is committed to achieving. I would like to hold open the right to provide supplemental calculations should the Company provide this information at some future date. To date, no DSM programs, savings levels, or costs have been provided so any estimate on earnings at this point is hypothetical. Assuming that this data were available, a forecast of earnings impacts could be developed that examined the anticipated change in revenues that was created by the implementation of DSM. These forecasts would need to estimate the expected revenue growth net of DSM (a calculation similar to those calculated in a projected test year). Thus, anticipated revenue growth less losses from DSM would result in a forecast of net-DSM related revenue growth. This, in turn, would be compared to forecasts associated with other cost and financial changes in order to determine the impact on earnings.

<u>IV USE PER CUSTOMER DATA</u>

Q DOES THE COMPANY'S CET PROPOSAL HAVE ANY SPECIAL IMPACTS GIVEN THE BROAD AGGREGATION OF DIFFERENT CUSTOMER TYPES IN THE GS CLASS?

A It could for two different reasons. First, if the forecasted GS class composition is moving more in the direction of residential customers, as opposed to commercial customers, and if forecasted residential use per customer is falling at a rate faster than commercial use per customer, then commercial customers may be called upon to cover revenue shortfalls associated with decreasing residential sales (holding other factors constant). Second, the potential inequities could be even greater if the DSM programs promoted by the Company primarily target residential customers. Thus, commercial customers will bear the full costs of revenue decoupling, in terms of covering revenue shortfalls and contributing to DSM implementation costs, potentially receiving little if any benefits.

Q THE STAFF HAS ASKED A NUMBER OF QUESTIONS RELATED TO THE JOINT APPLICANTS' EXHIBIT REFLECTING TEMPERATURE ADJUSTED USE PER CUSTOMER. CAN THEIR QUESTIONS BE ANSWERED FROM ANY OF THE DATA PROVIDED BY THE COMPANY?

A No. The data provided in SR Exhibit CCS-2.12 represents a time series graph showing monthly use per customer since 1981. The graph shows many changes over the past 20 years. However, it is difficult to ascertain the reasons and justifications for these changes since, as I noted in my rebuttal testimony, the Company has been unable to provide any of the supporting documentation for this graph. Thus, it is difficult to determine what impacts various factors like price changes, income changes, appliance standards, tariff shifts, regulatory changes, among other factors, have specifically had on use per customer over the time period presented in SR Exhibit CCS-2.12.

Q DOES THE STAFF'S QUESTION RAISE ANY IMPORTANT ISSUES?

A Yes, the Staff's question recognizes that there are a considerable number of factors impacting usage per customer that go beyond DSM. A broad decoupling approach like that proposed by the Joint Applicants would shift all of the risk associated with the various factors listed by the Staff onto ratepayers. This is why one of the alternatives I presented earlier would attempt to adjust for many of these changes. First, weather-related changes are generally already accounted for in the data since it is provided on a weather-adjusted basis. Second, impacts due to changes in price and the economy would be picked up in the income and price elasticity adjustments I discussed earlier. Third, exogenous factors, like those associated with greater overall appliance efficiency and improved building codes, will be picked up in the trend adjustment factor.

Q WHAT ARE THE REASONABLE LEVELS TO WHICH USAGE PER CUSTOMER CAN FALL?

A This is an important question which has no answer in the Joint Applicants' CET filing. In my opinion, understanding the cost-effective levels by which the Company can reduce natural gas usage is an important policy question that needs to be considered in conjunction with the CET proposal. This conclusion was also reached in the technical conference by Ken Costello, author of the NRRI report on revenue decoupling, who participated by phone. He clearly indicated that any decoupling proposal should be accompanied by a full set of DSM programs. To date, the Company has provided little information on potential DSM programs, and has indicated that some information will be available at the hearing. However, Nexant is only preparing a survey of gas efficiency programs with savings and cost estimates. Recommendations for DSM programs in the detail that utility ratemaking requires are not contemplated. This gives parties little to no time to (1) review the potential savings relative to the CET proposal and (2) being able to critically examine the programs, estimated costs, or savings being offered as a benefit for having the CET approved.

Q HASN'T THE COMPANY INDICATED IT IS IN THE PROCESS OF PREPARING A LIST OF THESE DSM PROGRAMS AND SHOULD HAVE THEM READY FOR REVIEW AT THE HEARINGS?

A Yes it appears that the Company has recently taken action in developing a roadmap for program identification. However, it filed its joint application on December 16, 2005. It was not until around May 9, 2006, only 6 days before interveners filed testimony critical of the Joint Applicants' proposal, that some type of firm action was taken on identifying DSM programs that would be in place during the pilot period.[3] At that time, the Company started negotiations to secure the services of Nexant, a consulting firm with expertise in the research and development of DSM programs. The Company did not execute a formal contract with Nexant until May 25, 2006. The contract at present appears to authorize only a market and delivery survey. Moving forward with any DSM activity, while late in this process, is a positive step. But the details of the programs, the level of commitment associated with these programs, and the total costs associated with the programs are still unknown.

Q ARE THERE ANY STUDIES THAT HAVE EVALUATED THE CHANGE IN USAGE PER CUSTOMER CREATED BY NATURAL GAS PRICE SPIKES?

A The Company indicates that it has a price elasticity of demand of -0.06 on a use per customer basis. This means that a one percent increase in price results in a decrease of natural gas usage per customer of 0.06 percent. However, natural gas prices have increased and decreased over the past several years resulting in positive and negative price-created usage changes. Taking

[3] Response to Committee of Consumer Services Data Request CCS 5.03.

this elasticity factor, and applying it to the changes in retail prices (average revenues) since 2001, yields an estimated total (net) period decrease in usage of roughly 14,540 Dth.

Q ARE THE MORE RECENT CHANGES IN USE PER CUSTOMER STATISTICALLY SIGNIFICANT?

A No. SR Exhibit CCS-2.13 presents the summary statistics needed to evaluate the statistical significance of the Company's recent changes in use per customer since 2000. The most recent year's usage per customer of 112.8 Dth would appear to be much lower than the 2001 level of 118.9 Dth. However, this level is nowhere close to being meaningfully different from the most recent five-year average (on a statistical basis).

Q WHAT DO YOU MEAN WHEN YOU SAY THAT THE CURRENT LEVEL IS NOT STATISTICALLY DIFFERENT?

A This is not an extraordinary, or abnormal shift given recent trends in use per customer over the past five years. Use per customer has moved, either above or below the sample mean, by approximately 2.76 Dth. This 2.76 Dth represents the standard deviation from the sample mean during the five year period. Generally, deviations around the sample mean are considered statistically significant when they are greater than two times the standard deviation, which in this case would be +/-5.52 Dth. The difference between the average use per customer for the sample period and the most recent year is only -3.26 Dth, well below the +/-5.52 Dth threshold of statistical significance.

Q IS THERE ANY STATISTICALLY SIGNIFICANT DIFFERENCE IN AVERAGE REVENUE PER CUSTOMER?

A No, and in fact, the difference between the most recent year's DNG revenues per customer and the five-year average are even less significant. The summary statistics analyzing these trends are provided in SR CCS Exhibit-2.13. The five-year average revenue per customer is $275.32 and the standard deviation in the Company's average revenue trend is $7.19 per customer. The recent decrease in revenue per customer to $274.82 differs from the five-year average by only $0.51 per customer, which amounts to $400,000 at 2005 customer levels, and less than 1 cent per Dth. Further, as I noted in my rebuttal testimony, the $274.82 in revenue per customer in 2005, while lower than 2004, is higher than the levels in 2001 ($270.50).

Q HAVE YOU DONE ANY ANALYSIS OF THE CHANGES IN THE COMPANY'S USE PER CUSTOMER INFORMATION?

A Yes. SR Exhibit CCS-2.14 presents a replica of the Company's analysis, with an inset chart showing major period trends in the data. Three major periods are visible in the chart and are outlined in the inset table. From 1981 to mid-1987, use per customer was decreasing at a rate of about 5.4 Dth/customer, a relatively rapid decrease. However, the decade spanning 1987-1997 saw use per customer flat to slightly increasing (0.386 Dth per customer). Since 1997, usage per customer has fallen by 3.7 Dth per customer. However, this period has its own set of trends. For instance, from mid-1997 to late 1998, use per customer decreased at a rapid pace of roughly 8.8 Dth per customer. From late

1998 to the spring of 2002, the decreases in use per customer moderated to a still healthy reduction of 4.0 Dth per customer, and for the last four years, from spring 2002 to current, the decrease has been much more modest, indicating a reduction of roughly 1.0 Dth/customer, considerably lower than the more recent five-year average.

Q HOW HAS USE PER CUSTOMER CHANGED OVER THE PAST FIVE YEARS?

A SR CCS Exhibit-2.14 shows the more recent trends in use per customer from the information provided by the Company in its Application (see "Recent Trends" section of the inset table). For the overall five year period, use per customer has fallen by an average of 2.4 Dth/customer. Each year, these decreases have moderated. Reductions in use per customer have decreased from 6 Dth/customer in 2001 to last year's reduction of 1.2 Dth/customer.

Q HOW WOULD YOU INTERPRET THESE RECENT TRENDS?

A The recent trends would suggest that the decreases in use per customer are getting smaller relative to historic trends. Assuming large decreases in use per customer in the future, while still an empirical issue that deserves considerably more analysis, may be unreasonable.

V. CHANGES IN RISK AND RISK SHIFTING

Q NRRI LISTS THREE CONDITIONS THAT WOULD SUPPORT REVENUE DECOUPLING. ARE ALL OF THESE CONDITIONS PRESENT IN UTAH?

A No. The three conditions listed by NRRI are also identified by Staff in their issues list. The supportive conditions include: (1) forecasted decreasing use per customer; (2) static customer base; and (3) decreased usage per customers not reflected in the ratemaking process. Conditions (2) and (3) are not present in Utah. Questar has a rapidly growing customer base, and its most recent IRP anticipates 2006-2007 growth to be 25,000 customers per year for each year. From 2008 forward, the Company anticipates growth of 22,000 customers. The current ratemaking process should allow the utility to reflect the test year decreases in use per customer. So of the three conditions, two are not present in Utah. Condition (1) is present, but the extent to which these decreases will continue, is questionable.

Q DOES THE WNA AND GAS PASS-THROUGH MECHANISM INCREASE OR DECREASE THE BENEFITS OF REVENUE DECOUPLING?

A The WNA and 191 Account provide no real meaningful benefit to the CET proposal nor to revenue decoupling. In other states where revenue decoupling has been debated, risk shifting associated with weather has often been contentious. Weather risk is less of an issue in this proceeding since the Commission already has a WNA in place to address this form of risk. However, the presence of both of these mechanisms does raise larger questions about the Company's unwillingness to promote DSM. The Commission allows the Company to receive significant benefits, in terms of being able to mitigate business risk, from the presence of the WNA and the 191 Account. These are benefits that many utilities in the U.S. would find supportive of DSM development and in fact, are benefits that some gas utilities do not get, and yet still provide cost-effective DSM for their customers. Despite these benefits and the recognition that cost-effective DSM opportunities exist, the Company appears to be unwilling to implement cost-effective DSM until virtually all revenue risk is eliminated from its current rates.

Q HOW WOULD THE PROPOSED CET IMPACT COMPANY FINANCIAL RISK?

A. As I noted in my rebuttal testimony, the proposed CET would shift the risks associated with changes in price, the economy, and other factors like greater economy-wide energy efficiency, away from the Company and to ratepayers without any offsetting shifts in rates.

Q WOULD IT BE NECESSARY TO MAKE A COST OF CAPITAL ADJUSTMENT IF THE CET IS ADOPTED?

A A cost of capital adjustment is one way to address the Company's reduction in business risk. Other jurisdictions have recognized this opportunity in their review of revenue decoupling proposals. As noted by a Division representative in the technical conference, it may be difficult to make such an adjustment since the current allowed cost of capital was developed during the last rate case. A financial revenue decoupling adjustment, however, would be based upon current financial information creating a potential mismatch in financial information for ratemaking purposes. While the Company has recently updated its rates to reflect adjustments in its capital structure, it has not made corresponding adjustments to all of the rate elements. Thus, it may be difficult to make a cost of capital adjustment in this proceeding without a full rate case. If the Commission were to adopt the partial revenue decoupling alternative I discussed earlier, a considerable amount of this risk would remain with the Company, and an immediate cost of capital adjustment may be unneeded, at least for pilot program purposes.

Q ARE YOU AWARE OF ANY ANALYSES THAT HAVE IDENTIFIED THE FINANCIAL IMPLICATIONS OF RISK SHIFTING ASSOCIATED WITH REVENUE DECOUPLING?

A Yes, Moody's Investor Service ("Moody's"), in a June 2005 Special Comment on natural gas utilities, noted:

> Moody's believes that having utility rate designs that compensate the gas LDC for variations in conservation as with variations in weather would serve to stabilize the utility's credit metrics and credit ratings.[4]

Further, revenue decoupling can impact the business risk categorization under which utilities are judged by Standard and Poor's. This categorization, based upon business risk profiles, includes a measure for utilities that face supply and volumetric risk. Those with high risk are in the higher categories (highest risk category is 10), while those utilities that face lower risks by having adjustment clauses, are moved to lower levels. NW Natural, a gas distribution utility in Oregon that has both a PGA and decoupling mechanism, was able to lower its rank to 1, the lowest level category.

Q DOES REVENUE DECOUPLING HAVE ANY POTENTIAL IMPACT ON DEBT?

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[4] Moody's Investors Services. *Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector*. June, 2005: 8.

A Yes. Moody's recently reiterated the strong benefits revenue decoupling would provide in maintaining shareholder value. Such a mechanism will maintain strong credit metrics and improve credit ratings relative to utilities that do not have such mechanisms since revenue decoupling eliminates shareholder exposure to risk and volatility from price and climate changes.[5] Further, according to a recent review of the NW Natural decoupling program:

> [NW Natural] CFO David Anderson believes that DMN [Distribution Margin Normalization] and WARM [Weather Adjusted Rate Mechanism] were contributing factors to NW Natural obtaining the best rating in the Standard & Poor's (S&P) business risk profile (scoring a 1 on a scale of 1 to 10). Similarly, he believes that DMN and WARM contributed to the upgrade in NW Natural's S&P bond rating from A to A+. An improved risk profile has several beneficial effects. It allows NW Natural to maintain smaller lines of credit, reduce the share of equity in its capital structure, and maintain a lower coverage ratio.[6]

Q DURING THE COURSE OF THE TECHNICAL CONFERENCE, SOME PARTIES INDICATED THAT AN ADJUSTMENT FOR LOWER BUSINESS RISK WAS RELATIVELY UNIMPORTANT AND THAT THE PROPOSED CET WAS A HARMLESS "GARDEN VARIETY" DECOUPLING PROPOSAL THAT SHOULD BE ADOPTED IN ITS CURRENT FORM. DO YOU AGREE WITH SUCH AN ASSESSMENT?

A No. If making these types of risk adjustments are not that important, then they should be required as part of this proceeding. Clearly, as I noted earlier, Wall Street (as reflected in two different Moody's reports) finds these adjustments very important in the potential risk insulation they provide to investors. Failure to

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[5]Moody's Investor Services. *Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*. June 2006.

[6]Christensen and Associates. *A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural Gas*. March 31, 2005: 72.

make these risk adjustments results in giving the utility an admitted windfall in its allowed return. This amounts to bad regulatory policy and is inconsistent with setting rates in a fair, just, and reasonable manner. The Commission should reject any recommendations in this proceeding that would dismiss this basic principle of regulation so easily.

Q DO YOU AGREE WITH THE POSITION THAT MAKING A DOWNWARD COST OF CAPITAL ADJUSTMENT AT THIS POINT IN THE DSM DEVELOPMENT PROCESS WOULD SEND A BAD SIGNAL TO THE UTILITY?

A No. Failing to recognize the risk shifting inherent in this proposal would result in rates that, by definition, were not fair, just, and reasonable – regardless of degree or magnitude. To do so without attempting to make any reasonable adjustment essentially allows the utility to claw into the very monopoly profits that regulation is intended to control. Given the current CET proposal, not correcting for this would be especially problematic since no definitive list of DSM programs has been provided to date.

Q COULDN'T YOUR PROPOSED PARTIAL DECOUPLING ALTERNATIVE BE USED IN LIEU OF MAKING THIS ADJUSTMENT?

A Yes. A partial decoupling approach would be one method by which risk shifting could be minimized at least for pilot purposes.

Q DURING THE TECHNICAL CONFERENCE, THE JOINT APPLICANTS INDICATED THAT THEY CONSIDERED USING ELASTICITY ESTIMATES TO

ADJUST FOR RISK SHARING, BUT FOUND IT TO BE TOO COMPLEX. DO YOU AGREE WITH THIS POSITION?

A No. In fact, the Company's application explicitly recognized that the type of adjustments I have proposed through a partial decoupling approach (also known as a statistical "re-coupling" approach) are superior to the form of revenue decoupling included in the proposed CET. In Exhibit 1.7 of the Company's application it states, "[t]he recoupling is an **<u>improvement</u>** that could easily be added at a later time, if desired." Further, the Company's technical hearing expert has also recognized the improvements associated with these types of adjustments in his testimony and filings in other states. In a filing in California, the Natural Resources Defense Council ("NRDC") states that the "[it] is open to exploring alternatives that shift more weather and business-cycle risks to utilities."[7] The NRDC filing notes that California's ERAM ["Electric Rate Adjustment Mechanism] "involves a 'true-up' of actual electricity sales to match forecasted sales; adjustments for weather or the local business cycle could be built into the true-up system." The NRDC filing then points to the ORNL report, *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues*, as an example of how this re-coupling may be accomplished. However, the Company and the Joint Applicants indicated during the technical conference that they really didn't want this proposal to get to the "Ph.D. level." This justification simply short-changes ratepayers, and as I noted earlier, is entirely inconsistent with setting fair, just, and reasonable rates. While

[7] "Comments of the National Resources Defense Council on Customer Choice through Direct Access: Role, Structure and Efficacy," National Resources Defense Council, Before the Public Utilities Commission of the State of California, R.94-04-031, August 23, 1994.

having a Ph.D. might be helpful in reviewing the appropriate elasticity estimates, it doesn't take a Ph.D. to figure out which party benefits from the omission of these important risk adjustments: the Company and its shareholders. The appropriate data to make a re-coupling adjustment is available as part of the Company's load forecasting and IRP process, and should be used in this proceeding if other mechanisms, like an incentive-based approach, are not adopted.

Q WHAT BENEFITS DO CUSTOMERS GET FROM ASSUMING THE ADDITIONAL RISK ASSOCIATED WITH THE PROPOSED CET?

A Customers get no additional benefits from the proposed CET. Investors, on the other hand, stand to get considerable benefits by being insulated from a broad variety of factors impacting sales.

Q CAN THE PROPOSED CET IMPACT EFFICIENCY?

A Potentially. As I noted in my direct testimony, certainty in revenues creates better certainty for earnings. Lower revenue volatility allows a Company to better customize its operations. While the Company is correct in its assertion that the CET would not give it a guaranteed rate of return, and the Company is correct that it would still have to keep control of its cost structure, it is equally correct that revenue stability creates a comfortable environment for the utility to maintain the *status quo* without needing to aggressively looking for new sources of efficiency or cost reductions.

Q WOULD YOU AGREE WITH THE PREMISE THAT REVENUE DECOUPLING IS CONSISTENT WITH TRADITIONAL RATEMAKING?

A No. Revenue decoupling adjusts rates every year. Traditional regulation, however, sets rates on a "normal" test year basis, indicating that rates are set on normal company operations and typical conditions for the environment (period) in which the Company operates. Its allowed rate of return reflects the business risk that the utility faces and it is up to the Company to manage its operations in mitigating that risk and maintaining shareholder value. Thus, there is relationship between: (1) the normal test year, on the one hand; and (2) the allowed rate of return, on the other. If rates are adjusted every year, then the allowed rate of return needs to reflect that fundamental change in risk. Setting rates on a normal test year basis cannot be consistent with a mechanism that allows those rates to change every year. Under a revenue decoupling mechanism, every year becomes a "normal" or "typical year" for ratemaking purposes – which is clearly not the case.

Q ARE TEST YEARS TYPICALLY BASED ON "EXTREME EVENTS?"

A No, there is long history of state regulatory orders that note that typical test years should be based on normal conditions and not those associated with extremities. There are several state regulatory orders from the early 1980s, and the recession of the early 1990s, that reject the notion of using recession years as a test year. But if revenue decoupling were in place, like it was in Maine during the recession of the early 1990s, rates would be set on just exactly that kind of environment. As a result, the sales risk associated with the economy that would have traditionally been borne by the utility, was covered by ratepayers. Clearly this is inconsistent with traditional regulation.

Q ARE YOU SUGGESTING THAT THE UTAH ECONOMY COULD CRASH INTO A RECESSION SOON AFTER THE CET IS ADOPTED?

A No, this is not a likely event, and indications from the Company's IRP are that the Utah economy will continue to remain strong in the upcoming years. However, it is equally likely that Maine regulators did not intentionally adopt revenue decoupling in the early 1990s knowing that a full-blown recession was just around the corner and would saddle its ratepayers with over $50 million of lost revenues associated with an economic downturn. It is the law of unintended consequences that makes a broad and indiscriminating revenue decoupling proposal like the CET such a risky proposition. The CET proposal is very similar to that adopted by the Maine Commission and yet this "garden variety" form of revenue decoupling, that was adopted as a "harmless pilot program," and made no adjustments for exogenous shifts in utility business cycles, cost Maine ratepayers dearly. The Utah Commission should not make a similar mistake based on assertions about the harmlessness of a revenue decoupling pilot program in this proceeding, particularly when there are a number of other reasonable regulatory policy options at its disposal.

VI ALTERNATIVES COMPARISON

Q DOES THE COMPANY HAVE AN OBLIGATION TO PROVIDE DSM IF IT IS THE LEAST-COST RESOURCE?

A Yes. One of the hallmarks of least-cost planning is that demand and supply resources be evaluated on a comparable basis. Cost-effective DSM appears to not be getting equal footing in the Company's IRP process, despite its recognition that such cost-effective DSM alternatives are available.

Q IS IT PRUDENT FOR THE COMPANY TO FOREGO IMPLEMENTATION OF DSM IN THE ABSENCE OF A CET?

A No. If it can be verified that cost-effective DSM programs are available, a prudent utility should be actively pursuing such programs. However, entering into a prudence investigation, particularly at this stage of process, may be premature and Questar should be encouraged to continue with its recent efforts in DSM program identification and development. Nevertheless, while utilities should not be bludgeoned into implementing DSM, their failure to engage in least cost planning and to implement conservation and efficient programs should not be coddled either. Utility regulation is often a balancing of the use of "carrot" and "stick." Providing incentives can be an effective means of directing utility behavior, but begging, pleading, and offering an infinite number of concessions is not effective regulatory policy either. There are a number of opportunities for addressing the Company's concerns regarding DSM impacts on financial performance that are far less extreme than its proposed CET. Further, this proceeding would be good opportunity for the Commission to clearly lay out its expectations on the topic: namely, that if there are cost-effective DSM opportunities, the Commission expects the Company to be taking advantage of these opportunities, and DSM savings and goals should be included in the next IRP filing. There are a number of utilities around the country that have equally important statutory obligations as Questar, which provide a wide range of cost-effective DSM programs to their customers, and do not have a mechanism like the CET.

Q CAN THE USE OF A FUTURE TEST YEAR OFFSET SOME OF THE COMPANY'S PURPORTED DISINCENTIVES?

A Yes it can. Adjusting total projected sales for potential DSM savings is not an uncommon regulatory practice. Florida electric and gas utilities use projected test years and test year billing determinants are regularly adjusted for the forecasted DSM savings. The Florida Public Service Commission ("FPSC") recently estimated that Florida's electric utilities have saved some 4,951 MW and 5,488 GWh in electricity consumption through its DSM programs over the past 25 years. Florida electric utilities have a statutory obligation to provide least cost resources including DSM and are required to regularly appear before the Commission to forecast potential savings and set DSM goals for planning purposes.

Q WHAT ARE THE IMPACTS OF USING A FUTURE TEST YEAR AND REVENUE DECOUPLING?

A The use of a forecasted test year could help minimize true-up variations associated with the revenue decoupling mechanism. The degree to which these variations are minimized would be a function of forecast accuracy and unanticipated shocks in the exogenous variables used in developing the forecast.

VII RECOMMENDATIONS AND CONCLUSIONS

Q CAN YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A I maintain the same recommendations that were included in my earlier-filed rebuttal testimony that the proposed CET should be rejected. The CET shifts too many risks to customers and represents a significant departure from past regulatory practices. However, if the Commission is looking for a progressive policy for advancing DSM development, I have offered three different alternatives for consideration. All would represent a significant improvement over the currently proposed CET. Clearly, a number of additional details would need to be worked out with some, and perhaps all of these alternatives. However, given strong direction from the Commission, this could easily be accomplished in an expedited fashion.

Q DOES THIS CONCLUDE YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A Yes it does.